Deliverable 1.5
Report on the understanding of the character of the balancing problems and strategies for solving them. (long term)

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Abstract: This deliverable makes use of the reference scenarios established in D 1.3 for the analysis of the long-term balancing of increased amounts of fluctuating electricity production in the six regions defined in D 1.1 The analysis is partly based on the description of balancing technologies in D 2.3

1. Introduction

This deliverable describes the scenario calculations made for 2020 for the six regions chosen in D1.1. regarding long-term balancing of increased amounts of fluctuating and partly unpredictable electricity production

The regions are:

EST	Estonia
DK-W	Western Denmark
D	Germany
PL	Poland
E	Spain
SC-S	South of Scotland

Reference calculations have been carried out using the 7.01 version of the EnergyPLAN programme. The programme is introduced and explained in D 1.3. The updated version and manual can be found at [1]

In section 2, the economic assumptions used for the calculations are resumed.

In section 3, a number of scenario analyses for each region are presented. For practical reasons, only the technologies of special importance to the region in question are commented and explained. The role of CHP is not emphasized in particular as the benefits and potentials of CHP have been described in D 1.3

In section 4, the ongoing process of structural changes relevant for the balancing efforts in the transmission and distribution network for electricity is shortly described.

In section 5, the general conclusions are presented.

2. Economy assumptions

Fuel prices differ a lot between the regions. This is partly due to local conditions – in particular regarding different qualities of coal, but also due to different ways of incorporating the large oil price increases in the course of 2004. For 2020, even bigger differences were experienced. This can be explained by different attitudes regarding the development of the oil price. In Denmark and Spain, the official IEA forecast has been used, in which the present high level of oil prices is expected to be intermediate, while other countries have more pessimistic (realistic?) approaches. To make the calculations comparable it was decided in D 1.3 to use two sets of standard data for oil, N-gas and electricity. A low price scenario, 2020a, corresponding to the first attitude (26 $/brl) and a high price scenario, 2020b, corresponding to the latter (100 $/brl).

Since then, however, the IEA forecast has been adjusted upwards. It has therefore been decided to use energy prices based on IEA's World Energy Outlook 2006 as the sole price set for the calculations in this part of the project.

€/GJ	Coal	Fuel oil	N-gas	Biomass
Price (2015)	1,8 *)	5	5	4,4

*) for Estonia a lower price for the oil shale is used: 1,25 €/GJ

Prices are socio-economic prices including delivery to plant. (No taxes).

The use of this price set has two advantages:

- The results become comparable to other similar analyses (e.g. [2])
- The use of a ‘medium’ price set provides graphs, which show the differences between the different technologies more clearly (‘high prices’ tend to make every investment pay, while ‘low prices’ has the opposite tendency).

The average electricity price for the spot markets is assumed to be 47 €/MWh in 2020. This figure is based on a recent analysis performed by the software Balmorel by the Danish company ‘EA Energianalyse’ [2]. In this analysis, the future electricity markets of the Nordic countries and the northern part of the UCTE electrical grid area were simulated for the year 2025. Using official projections for electricity consumption and changes in the mix of production units, the mentioned average price was found to provide balance in the system.

Costs of investment and O&M of the various technologies concerned are based on official Danish estimates found in [3]. These costs are shown in Appendix 1.The costs of establishing wind turbines, however, have increased significantly during the last year. Therefore, the prices used in [2] are chosen: 1 M€/MW inland, 2 M€/MW off shore (including costs of connection to the inland grid).

A cost of 30 €/t for CO2 quotas and an interest rate of 3 % without inflation are assumed.

The balancing potential of the different scenarios considered for each region is evaluated by comparing the total socio-economic costs of production for electricity to meet the demand including any potential import or export of electricity. Because of the different levels of CHP plants involved in the production different amounts of the heating demand is covered by the same costs. For the individual region, however, this district heating demand is kept constant for all variations considered. This means that the variations for this region are compared correctly, but that the absolute levels of the total costs should not be compared among regions.

3. Scenario calculations

3.1 Estonia

Estonia has a relatively high capacity of interconnectors (230 % of the average capacity needed to cover the demand by import only). On top of that, an increase of CHP capacity to about 23% of the production is assumed for 2020. These factors facilitate the introduction of large shares of wind power. In fig. 3.1.1, it is seen how investment in wind power is profitable for the reference case up to about 70% of the demand (13 TWh). Investment and O&M costs of the necessary wind turbines are included in the calculation (see Appendix 1). A wind regime corresponding to 2500 full load hours is assumed. This corresponds to the best available positions along the coast. For the large shares of wind power, it will probably be difficult to find sufficient sites on the coast. In this case, the possibility of offshore wind power would be relevant, but this alternative has somewhat higher production costs because the double costs of establishment and operation are only partly balanced by the app. 50% higher production.

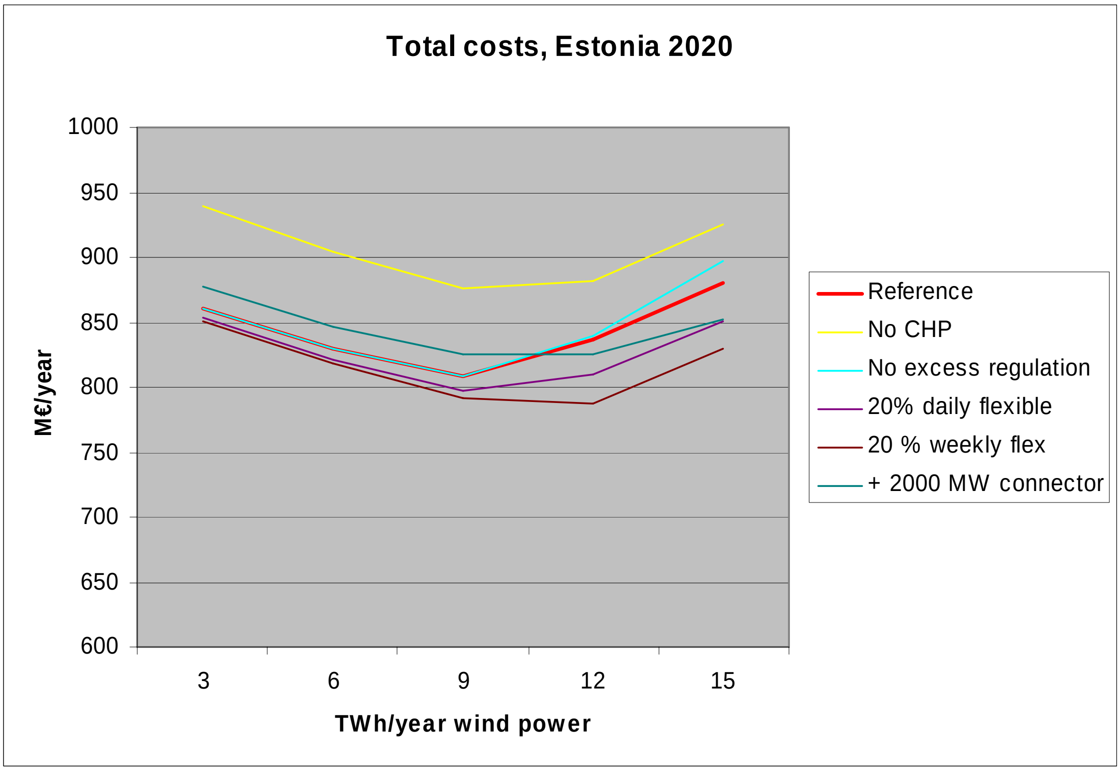


Fig. 3.1.1

In 2020, spot market prices in Estonia are assumed to vary like the prices on the German spot market unlike to day, where the liberalisation is not fully implemented.

An important limitation of these calculations must be stressed. The calculations are performed of the regions individually under the assumption that the neighbours do 'business as usual'. That means that price elasticity on the international markets is taken into account, but a situation in which the neighbours extend their wind power production in a similar way and need to export at very much the same hours as the region in question is not correctly described. This consideration is relevant for Estonia where the neighbours, eastward as well as westward, have similar wind regimes. The situation between Germany and Austria as an example is very different as wind power can be assumed to balance hydro power as long as the capacities are matching. The question whether unrealistic international balancing is assumed or not must be assessed carefully in each case.

The importance of the CHP plants is illustrated by the 'No CHP' graph of fig 3.1.1. It shows how the total production costs of electricity would increase if the CHP units were replaced by boilers using the same fuel (N-gas). The increase is partly due to the lower fuel efficiency of such a solution and partly due to the lower flexibility of this system.

The next graph shows the potential of the CHPs for handling possible excess electricity production beyond the export capacity of the interconnectors. They can A: shift from CHP production to boiler production, or B: shift from boiler production of heat to the use of electrical boilers. The graph shows how the total costs increase at very high shares of wind power only if these possibilities are not present and the only other option is used: C: cutting off wind power at hours of excess production. Because of the relatively strong interconnectors this becomes relevant at very high shares of wind power only.

The following graphs show the effect of the introduction of flexible demands. This can be implemented in various ways, normally by making use of thermal storage in connection with room heating and cooling or in connection with industrial processes. These possibilities are described in D 2.3.

It is seen how the positive effect of flexible demand is relevant only at wind shares above 70%, and that flexible demands with a time frame of a week make wind shares of nearly 100 % feasible. It is noted that the costs related to making the demand flexible and the operation and administration of this system are not included. These costs are difficult to evaluate – a lot of the flexibility does not require much investment, just a new way of trading.

Finally, a calculation on the economy of a further increase in the capacity of the interconnectors (from 2,5 GW to 4,5 GW) is made. It shows that it is profitable only at the very high levels of wind power. Attention is drawn to the remarks above regarding the possibilities of international balancing.

In the calculation above, the total investment in a 1000 MW interconnector is assumed to be 150 M€ (lifetime 30 years, O&M 0,5% of investment). This is much higher than the costs found in D 1.2 of the connectors as such , but an interregional transmission line normally requires costly strengthening of the internal grid. The total costs in the actual case are based on analyses carried out by the Danish Energy Agency [4].

In Fig. 3.1.3, the increase in interconnector capacity is illustrated. In the case of very high wind share (12 TWh), it is seen how the limitations on export are removed, and how the unwanted shifts from CHP production to boiler production are removed. On top of this, the even worse cut down on wind production is decreased.

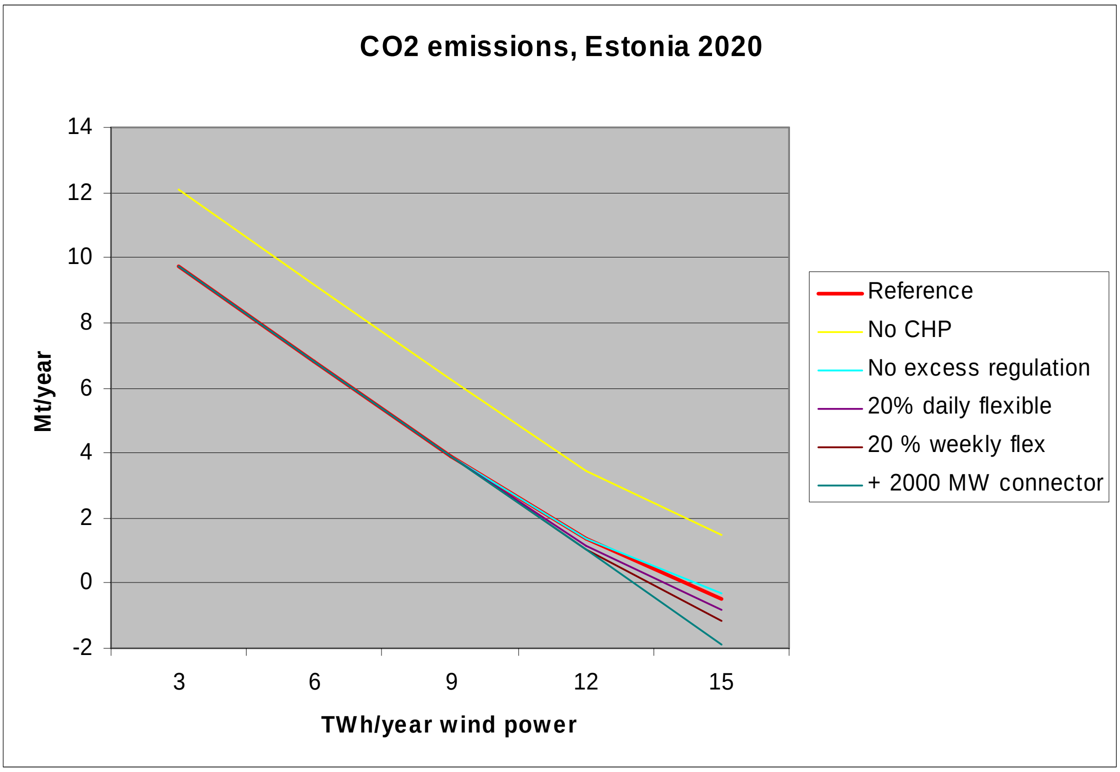
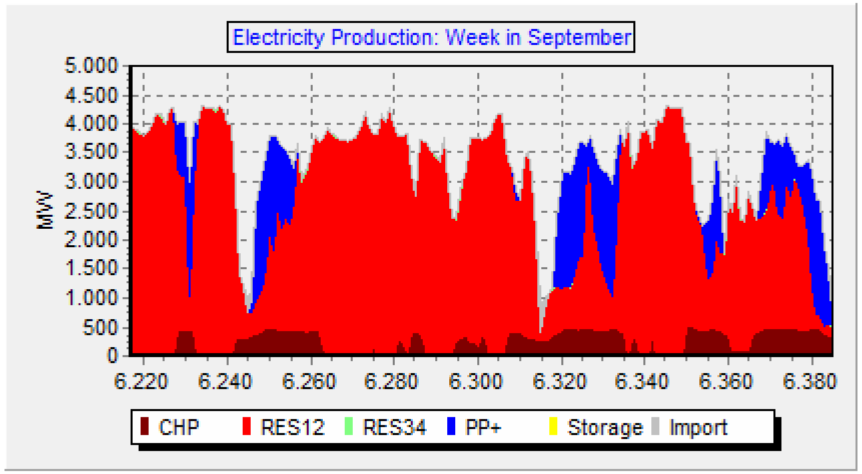


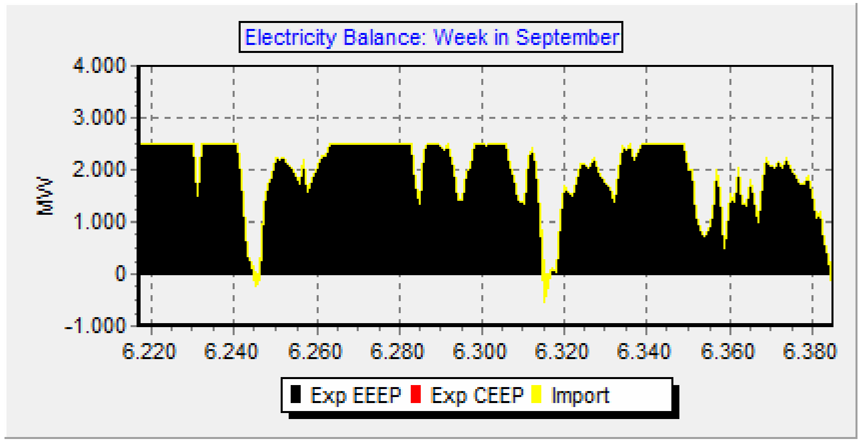
Fig. 3.1.2

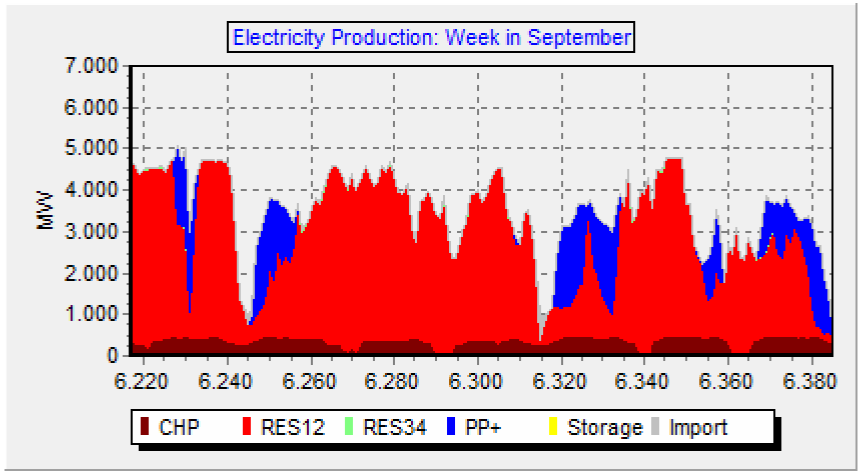
Fig. 3.1.2 shows the total CO2 emissions caused by the electricity production in Estonia in 2020 for the variations of the basic scenario described above. The CO2 emissions are corrected according to the net import/export of electricity for the region. For this correction, the coal power plant data regarding efficiency are used.

The corrected emissions are seen to be very similar except for the highest levels of wind power. The difference here is due to different amounts of wind power being lost because of limitations in the system’s ability to cope with peak productions.

CHP is seen to have an important effect on CO2 emissions due to the shift from coal to N-gas and the increase in total efficiency.


Electricity Production: Week in September
MW
5.000
4.500
4.000
3.500
3.000
2.500
2.000
1.500
1.000
500
0
6.220 6.240 6.260 6.280 6.300 6.320 6.340 6.360 6.380
CHP RES12 RES34 PP+ Storage Import


Electricity Balance: Week in September
MW
4.000
3.000
2.000
1.000
0
-1.000
6.220 6.240 6.260 6.280 6.300 6.320 6.340 6.360 6.380
Exp EEEP Exp CEEP Import


Electricity Production: Week in September
MW
7.000
6.000
5.000
4.000
3.000
2.000
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6.220 6.240 6.260 6.280 6.300 6.320 6.340 6.360 6.380
CHP RES12 RES34 PP+ Storage Import

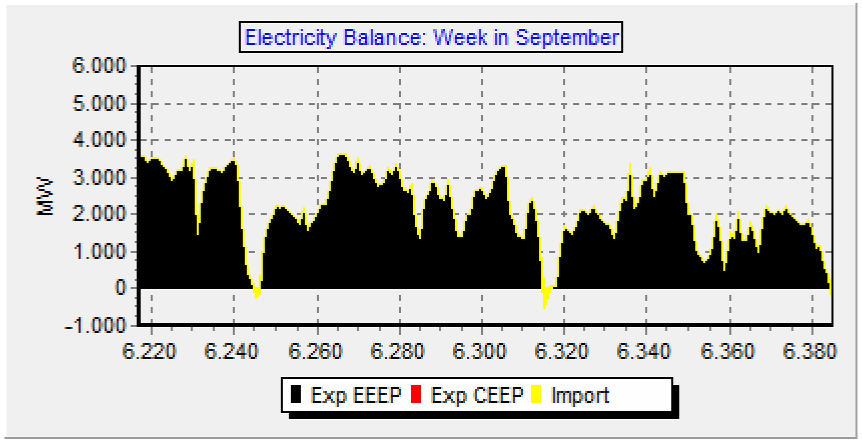

Electricity Balance: Week in September
MW
6.000
5.000
4.000
3.000
2.000
1.000
0
-1.000
6.220 6.240 6.260 6.280 6.300 6.320 6.340 6.360 6.380
Exp EEEP Exp CEEP Import

Fig. 3.1.3

3.2 Denmark-West

The Danish case has been described in some detail in D 1.4. In this connection, very much the same calculations as referred to in the case of Estonia have been carried out. The differences are that Denmark has a higher share of CHP (50%) and a lower capacity of interconnectors (70 % of the average capacity needed to cover the demand). For this reason, the optimal wind power level for the reference system is lower (app 50%).

In the first variation shown in Fig. 3.2.1, the CHP capacity is reduced by about 20% (1000 MWe). The increased costs show that the high level of CHP is profitable. (In the calculation, the decreased capacity of the CHPs is balanced by an increase of the capacity of the condensing power plants.)

The next calculations show the effects of increasing the interconnector capacity to the Nordic market (Hydro power) in two steps: From 1,7 GW to 3,7 GW and further to 5,7 GW. These connectors are assumed to involve twice the costs of the connectors used for Estonia because of the long distances involved, but the balancing relevance is of greater importance.

Because of the relatively low interconnector capacity, the excess regulating potential of the CHPs is more important than in Estonia.

Finally, the establishment of 200 MWe of heat pumps with a COP of 3,5 at the CHP plants is evaluated. The low temperature heat source could be condensing cooling of exhaust gas from N-gas engines (e.g. 20 dg.C) stored in a low temperature heat storage. As can be seen, this investment is economical to a wide range of wind power and is hence preferable to the increase of interconnector capacity. This is particularly interesting because this solution is decentralised and does not require the strengthening of the internal transmission system.

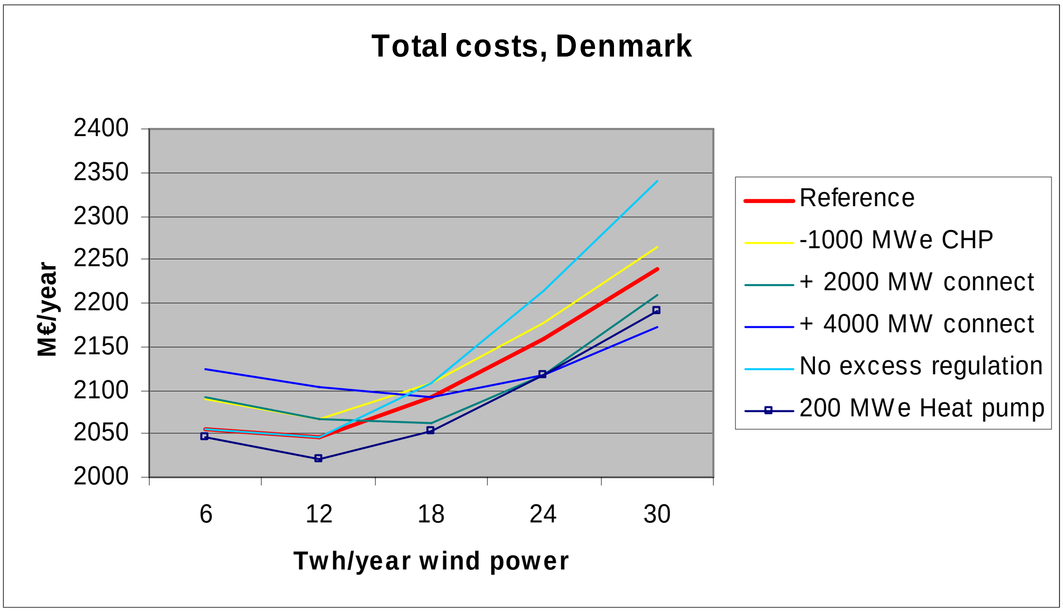


Fig. 3.2.1

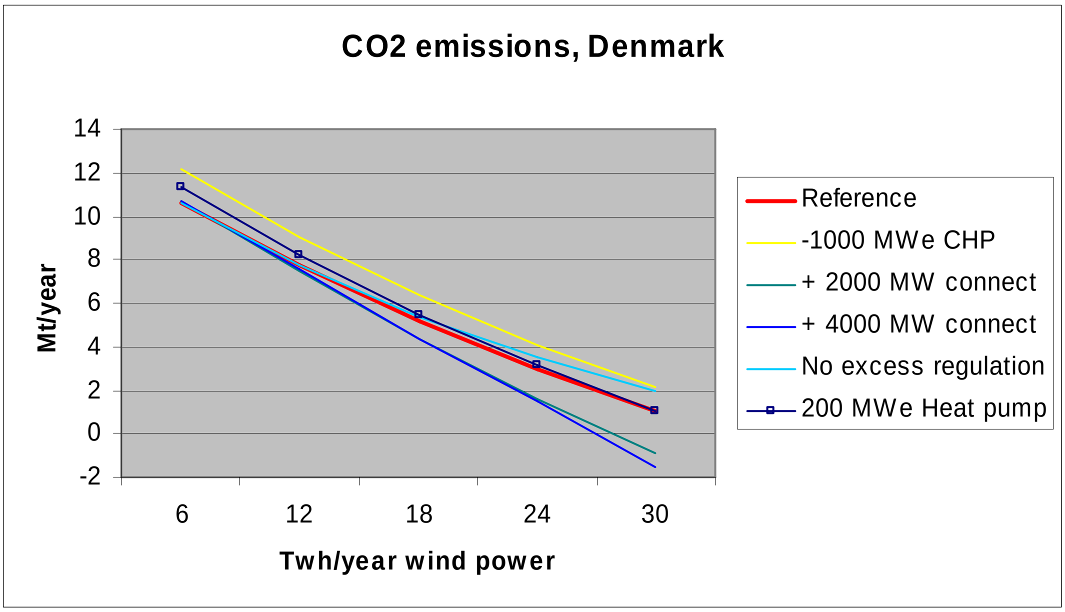


Fig. 3.2.2

The picture for the corrected CO2 emissions is similar to Estonia apart from the greater effect of the increases of the interconnectors. Negative CO2 emissions are possible because the high level of export connected to high shares of wind power is assumed to replace large amounts of electricity produced by coal. Even if the export goes mainly to Norway and Sweden, the reduction in coal power might in the final analysis take place in Poland or even Russia via the interconnectors internally in the Nordic system and the connections between this system and Russia, Estonia and Poland. (see D 1.2)

In Fig. 3.2.3, the function of the heat storages is illustrated. The situation shown concerns very high wind power levels (24 TWh equals 100% of demand). The capacity of the storages at the CHPs is assumed to increase from the reference situation, 25 GWh, (top line) to 70 GWh (bottom line).

It is seen how the increased storage is used for shifting CHP production in order to minimise PP production (condensing power plants) and boiler production of heat.

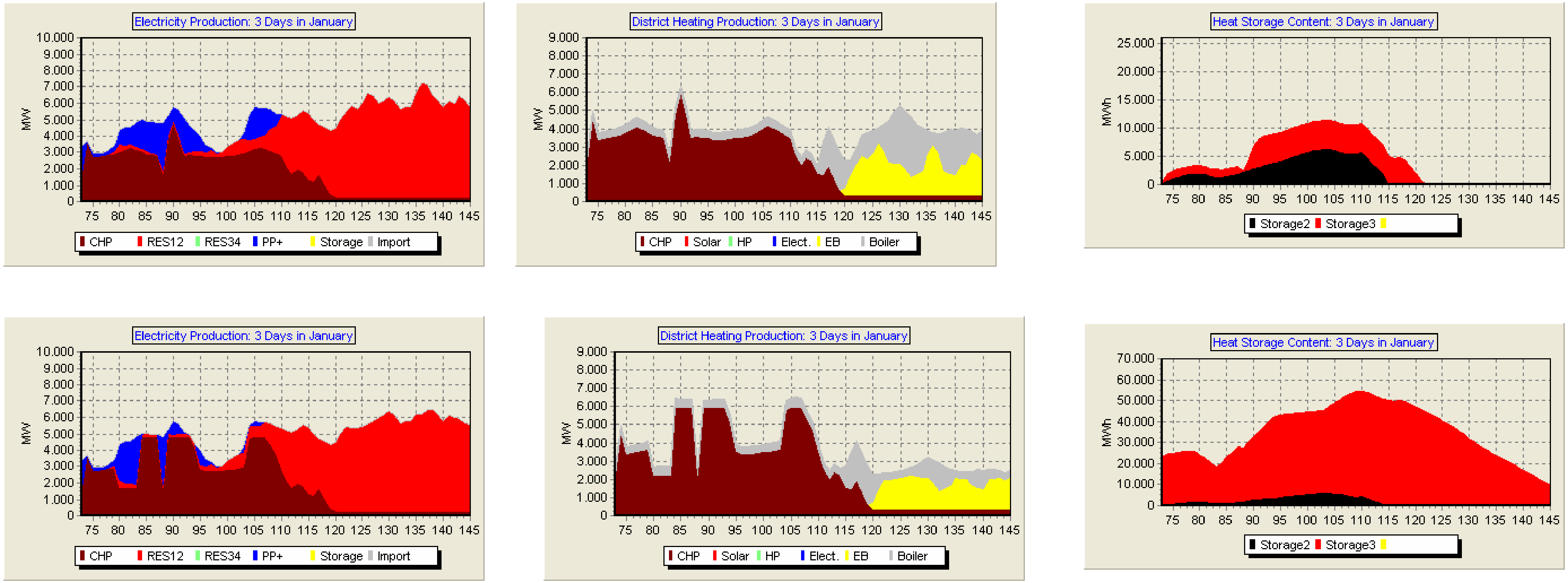


Fig.3.2.3 (RES=wind power, PP= power plant, EB=electrical boiler)

3.3 Germany

Germany has a relatively low capacity of interconnectors (app. 35 % of average capacity for covering the demand by import). In 2020, a share of about 20% of the electricity is assumed to be produced at CHP plants, while 8 % is inflexible nuclear power.

For these reasons, the optimal level for wind power is lower than in Estonia and Denmark: around 40% of the demand (500 TWh).

The variations of the reference conditions illustrated in figure 3.3.1 show that:

- CHP is profitable, particularly regarding the lower levels of wind power. (a decrease in capacity to 50% causes an increase in the total costs). In the German situation, very high levels of wind power result in relatively few operating hours of the CHPs, which cannot justify the higher investment and operation costs compared to condensing power plants.
- The establishment of 2000 MWe of heat pumps at the CHP plants (same specifications as used in the Danish case) has an important positive influence on the feasibility of wind power.
- The potential for regulating excess electricity at the CHPs becomes important at high levels of wind power like in Denmark.
- The introduction of about 20% flexible demand (either at a 24 hour or weekly time frame) has a very distinctive balancing effect. It is noted that the costs of establishing the flexibility are not taken into account.

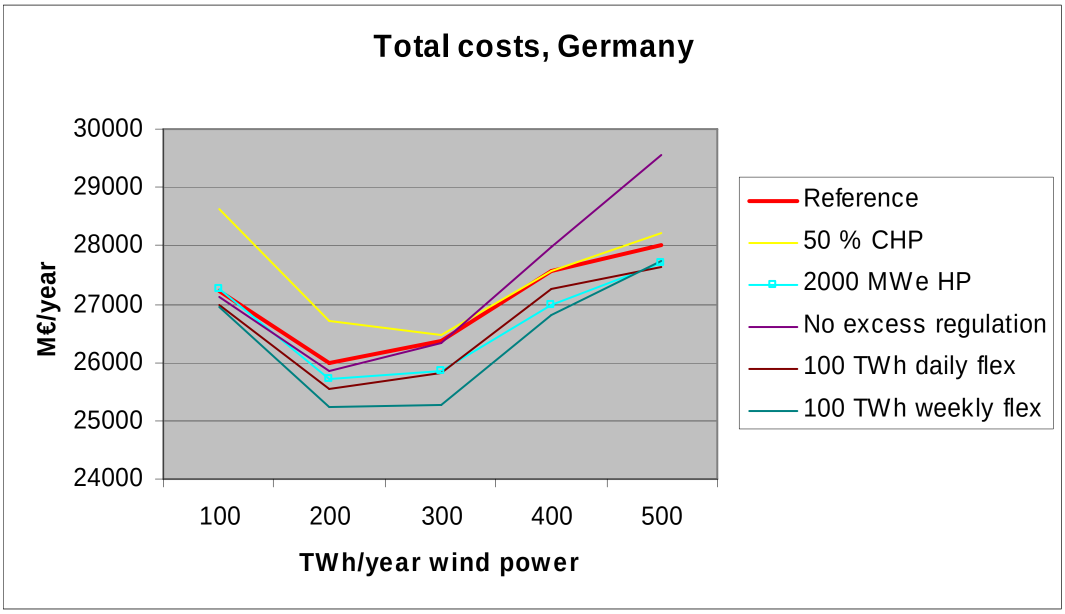


Fig. 3.3.1

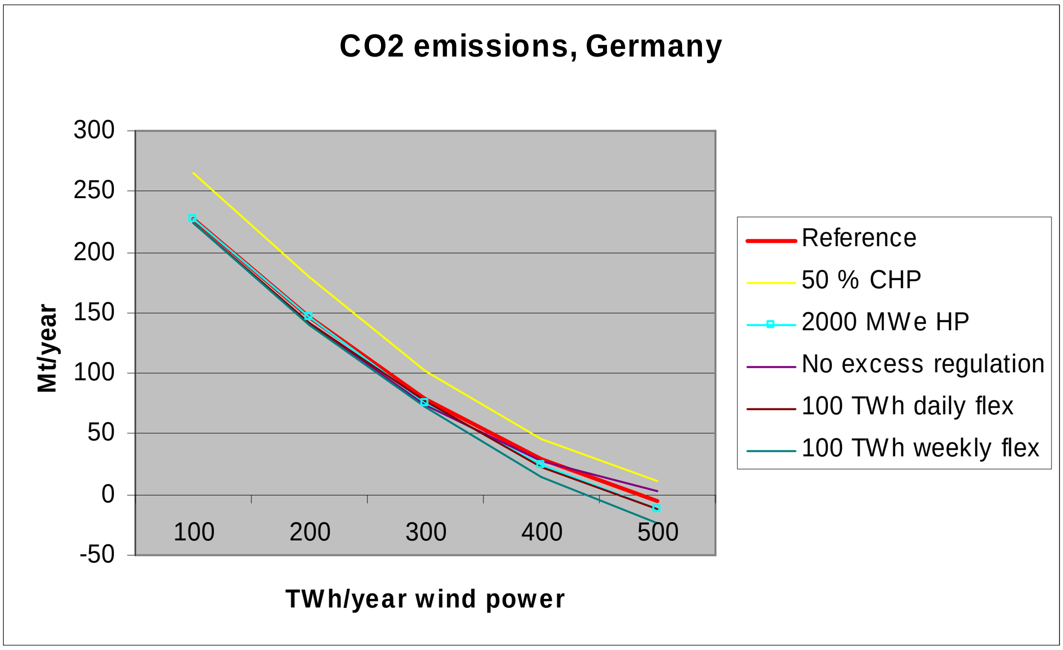


Fig. 3.3.2

The corrected CO_2 emissions show the same picture as for Estonia: Only the level of CHP production causes a significant difference.

3.4 Poland

The reference scenario in Poland resembles Germany but the relative interconnector capacity is lower (25%), the assumed CHP share is higher (25%) and there is no nuclear power.

Adding 2000 MW interconnector capacity is more or less economically neutral and does not improve the feasibility of wind power.

Lowering the capacity of CHP causes higher total costs at the lower levels of wind power, and substituting all CHP plants with condensing power plants causes a large increase in the costs at all levels of wind power. In this case, the amount of district heating is kept constant and heated by N-gas boilers. The lower total efficiency of this system causes higher fuel costs.

The introduction of heat pumps and/or flexible demands have not been tested for this region, but results similar to the Estonian and German cases are expected.

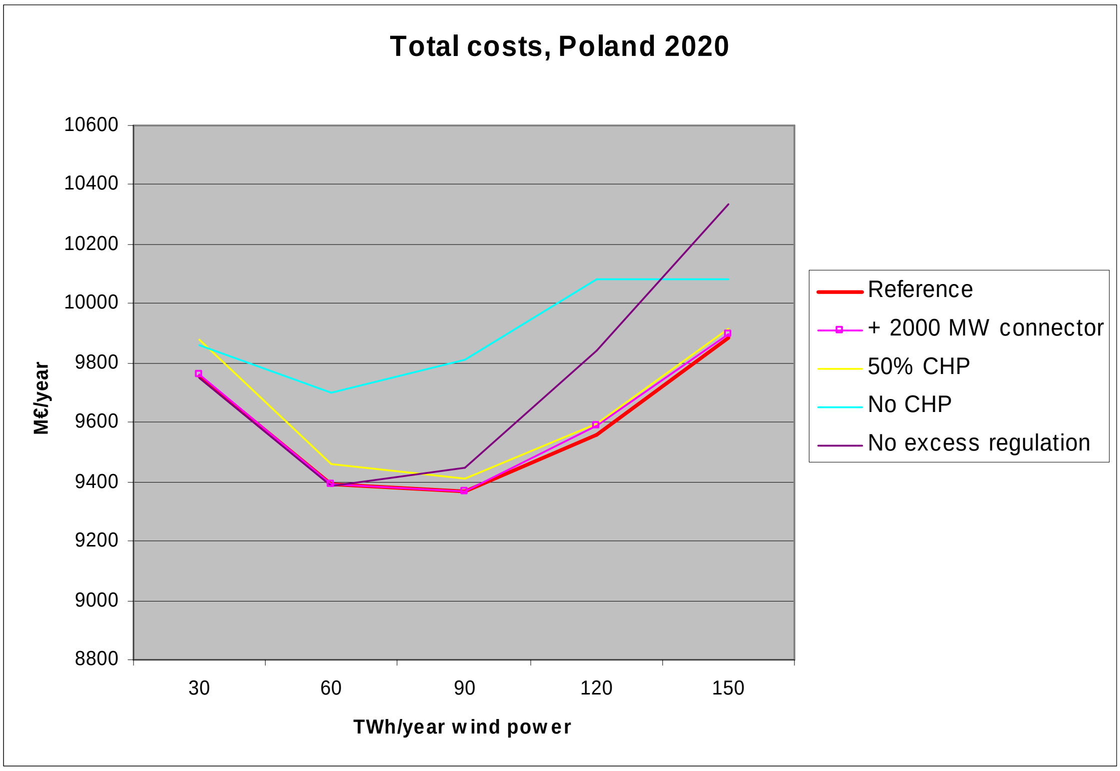


Fig. 3.4.1

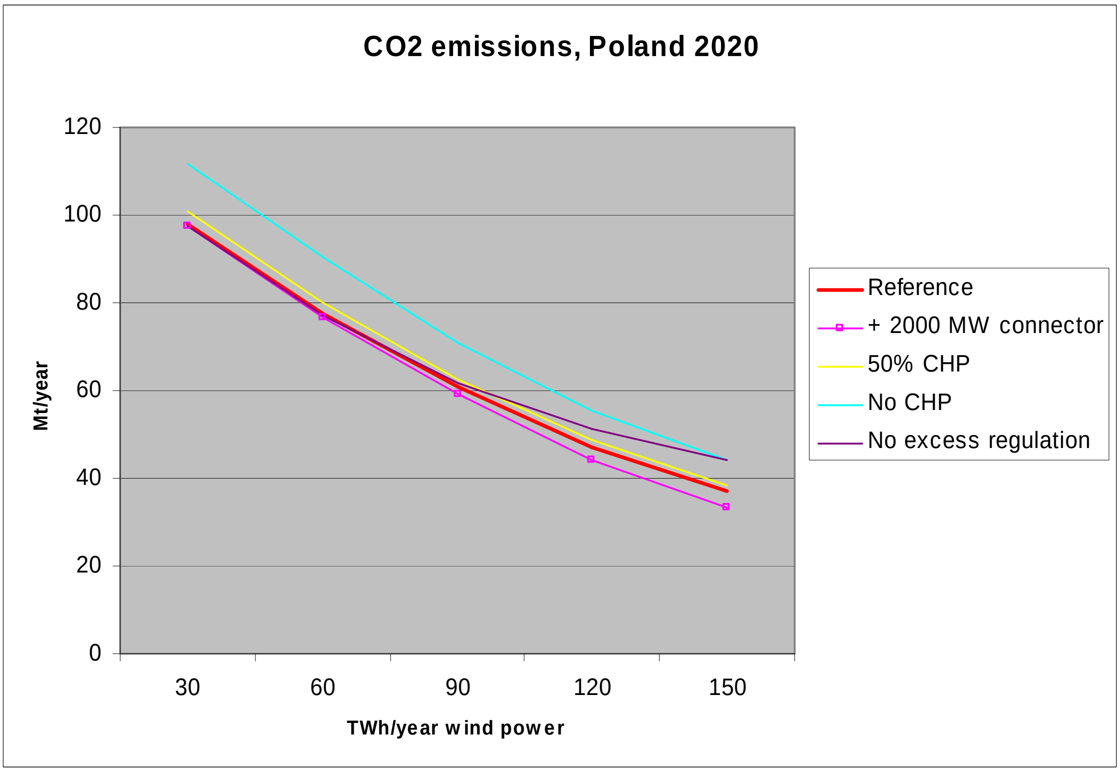


Fig. 3.4.2

For the CO_2 emissions, the same relative picture is seen as in Estonia and Germany, but in this case, negative values are not reached. This is due to the relation among coal-fired plants, the capacity of the interconnectors and the absence of nuclear power.

3.5 Spain

The situation in Spain is quite different from that in the central and northern European countries considered above. The heating demand is lower and hence the CHP solution is difficult to implement. (The possibility for combining heating and cooling demands is discussed below).

Interconnector capacities are rather weak (7% of average demand) and inflexible production (nuclear and industrial CHP) covers a relatively large share (25%). CHP is negligible but some flexibility is obtained by hydro power with reservoir and reverse pumping (9%).

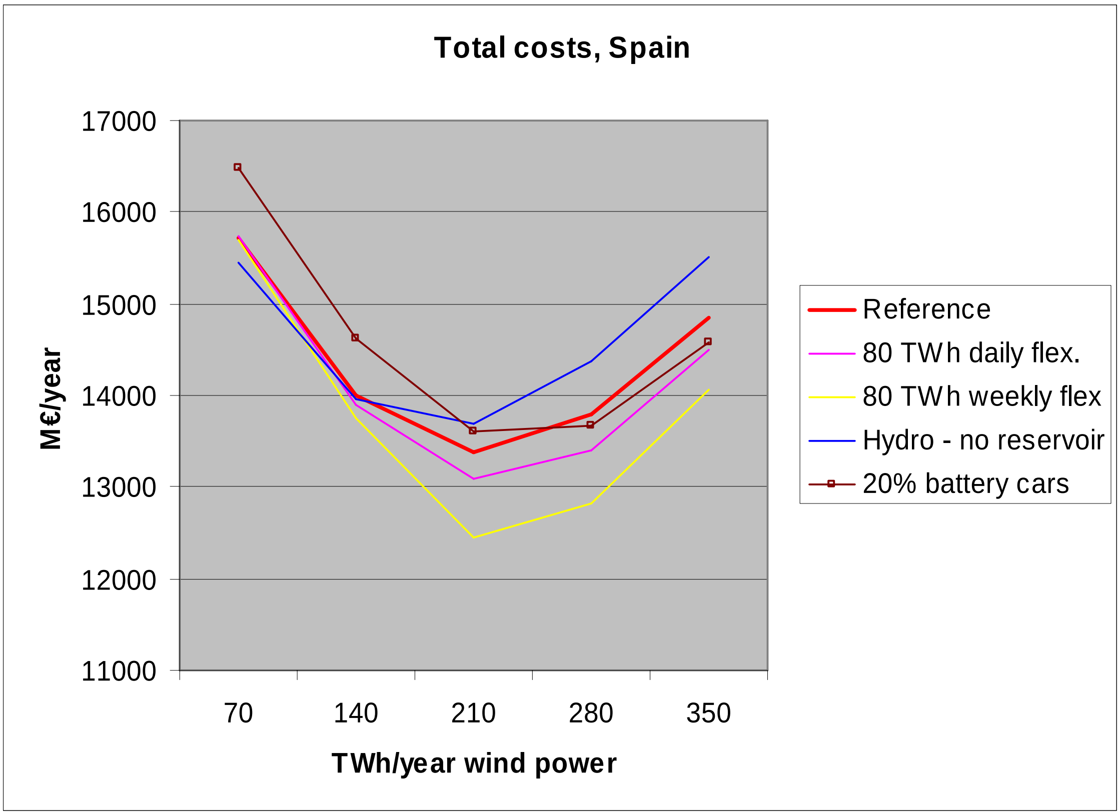
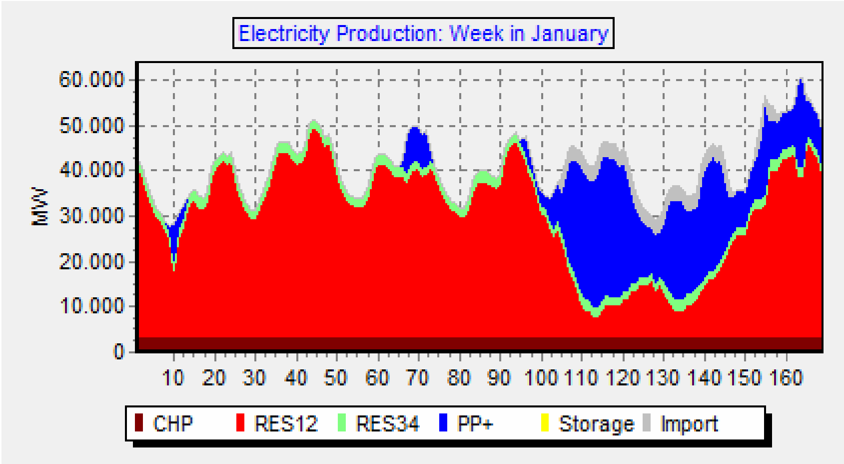


Fig. 3.5.1

Fig 3.5.1 shows how flexible demands increase the feasibility of wind power. In line with this, the negative effect is shown when not making use of the reservoirs of the hydro power for balancing purposes.

New technologies with balancing potential must, however, be introduced if further increases in the wind power capacity are wanted. In this case, the possibility of involving the transport sector is investigated. The assumption is made that 20% of all cars will be changed to battery cars. The electrical power needed in order to maintain the former amount of transport work is calculated to be 13 TWh/year. Because of the high efficiency of battery cars compared to petrol cars this electricity in turn substitutes 60 TWh petrol and lowers the CO2 emission with 15,9 Mt CO2. The costs of the investment are assumed to be 40% more than those of the corresponding petrol car, which is valued at 11000 € (socio-economic costs). It is underlined that this estimate of the extra cost prices is based on today's technology in the way that they are assumed to have dropped to half in 2020 as a result of the 13 years of development.

To maximise the balancing use of the batteries in this great number of cars the so-called Vehicle-to-Generator (V2G) operation is assumed. According to this method, the owners of the cars are motivated to keep the cars connected to the grid whenever they are not in use. This will make it possible for the system operators to load and to unload the batteries according to the balancing needs of the system. An intelligent control system in each car ensures that sufficient energy is available for the battery when it is needed by the owner. Figure 3.5.2 below shows how this functions in practice. In the case shown, the upper graph illustrates how the electricity demand is met in a situation with a high level of wind power, i.e. 75% of total yearly demand and without the battery cars. The lower graph shows how the batteries are used for lowering the production of the power plants (yellow=storage). The energy for this purpose has been loaded into the batteries at times when a surplus of power would otherwise have caused some turbines to be stopped.



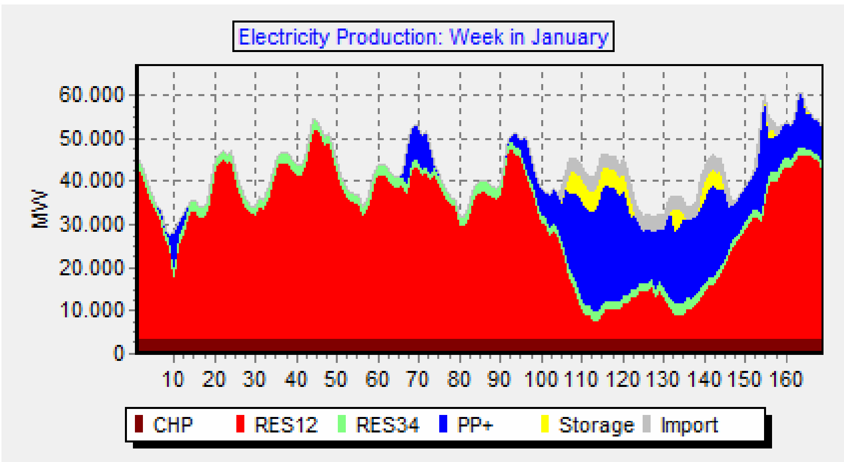


Figure 3.5.2. Production without (left) and with (right) battery cars.(RES12=wind power, RES34=hydro power and photo voltaic, PP=power plant).

In Fig. 3.5.1, it is seen how the introduction of battery cars as described above can shift the optimal level of wind power to the right. With the chosen cost estimate it is only profitable at very high wind shares, but the vertical position of this graph is questionable. If other benefits of the use of electrical cars like lower noise and pollution levels in big cities are included the picture might change completely.

As mentioned in the beginning of this section, one way of overcoming the difficulties regarding the establishment of district heating and CHP could be to combine district heating with district cooling by the so called trigeneration technology. With reference to section 5 of D 2.3, a calculation has been made in which 1000 MWe CHP is compared to the same capacity equipped with cooling devices. A simple solution in which an absorption cooling device with COP=1 is driven by the released heat of the gas engine is considered. A cold storage of similar capacity to the heat storage (app. 8 hours) is assumed. The investment and operation costs of this device are not considered. They are assumed to be balanced by the large number of individual electrical driven AC units which they replace. In this case, the district heating network is designed to be used for heating in the winter and cooling in the summer.

The resulting cooling is half of the heating demand (2,5 and 5 TWh respectively) and it is distributed according to the hourly distribution used for solar panels.

The result of this calculation shows that the regulating effect is too small to be seen in the graphs, but it is interesting to note that the economy is positive. Savings of app 50 M€/year are found for moderate levels of wind power, while lower savings are found at high levels because of the lower number of operating hours for CHP.

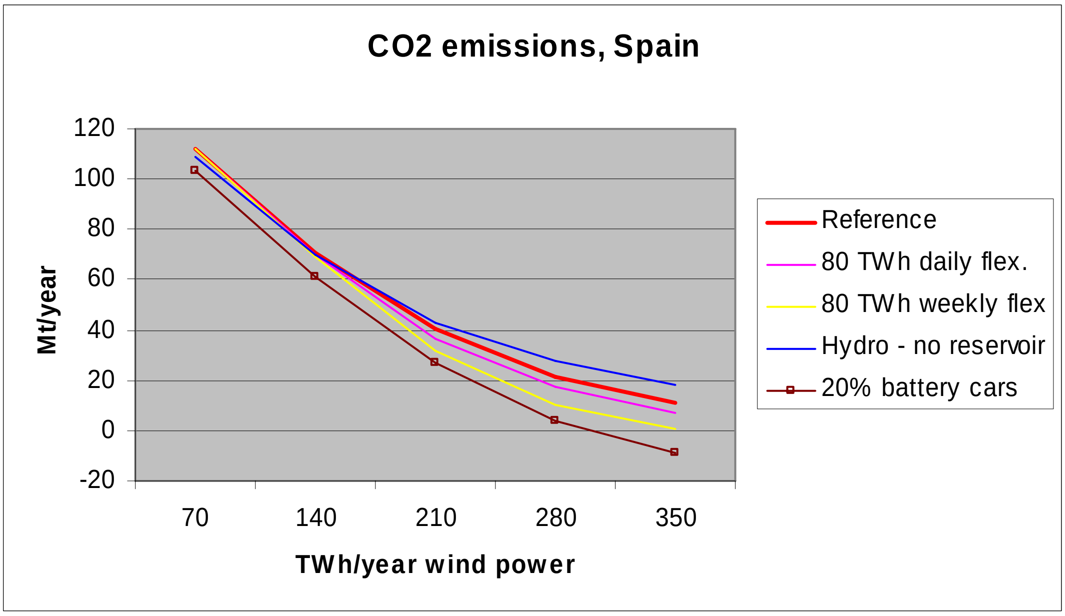


Fig. 3.5.3

Regarding CO2 emissions, the effects of the differences in flexibility are found to begin at lower wind power levels than seen in e.g. Germany. This is due to the low relative interconnector capacity. The stopping of wind turbines at peak production hours occurs at lower wind capacity levels, and whenever a wind turbine is stopped the missing production must be produced elsewhere – in these calculations by coal-fired condensation plants.

Battery cars have a distinctive positive effect on CO_2 emissions because of the petrol they substitute.

3.6 3.6 Scotland-South

The region Scotland-South is shown in fig. 3.6.1

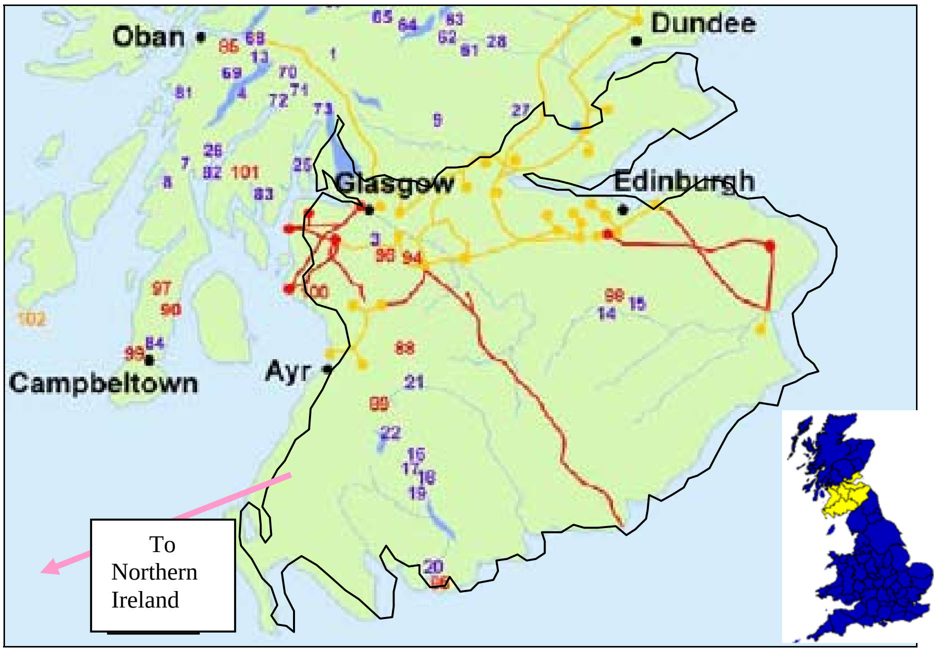


Fig. 3.6.1

It differs from the previous regions in the high interconnector capacity (170 % of average demand) and the high inflexible electricity production capacity (nuclear and industrial CHP – app. 50%). CHP with district heating is almost not existing, even in the forecast for 2020 (3%).

For the reference calculations, the total costs shown in fig. 3.6.2 have a clear minimum around 50% wind power. The copies of output graphs from the EnergyPLAN software shown in Fig. 3.6.4 illustrate this.

In the top row of this figure, the wind power production is 18 TWh/year (the optimum level). In the middle row, the capacity of the turbines has been increased in order to reach 24 TWh/year, but the interconnectors sometimes reach the limit for export and part of the new capacity must be cut off as the power plants have already been stopped. In the bottom row, an increase of 2000 MW for the interconnectors has been established and the whole wind power production can again be used. The graphs look very much like the top row except from the fact that the scales of the y-axis have been changed.

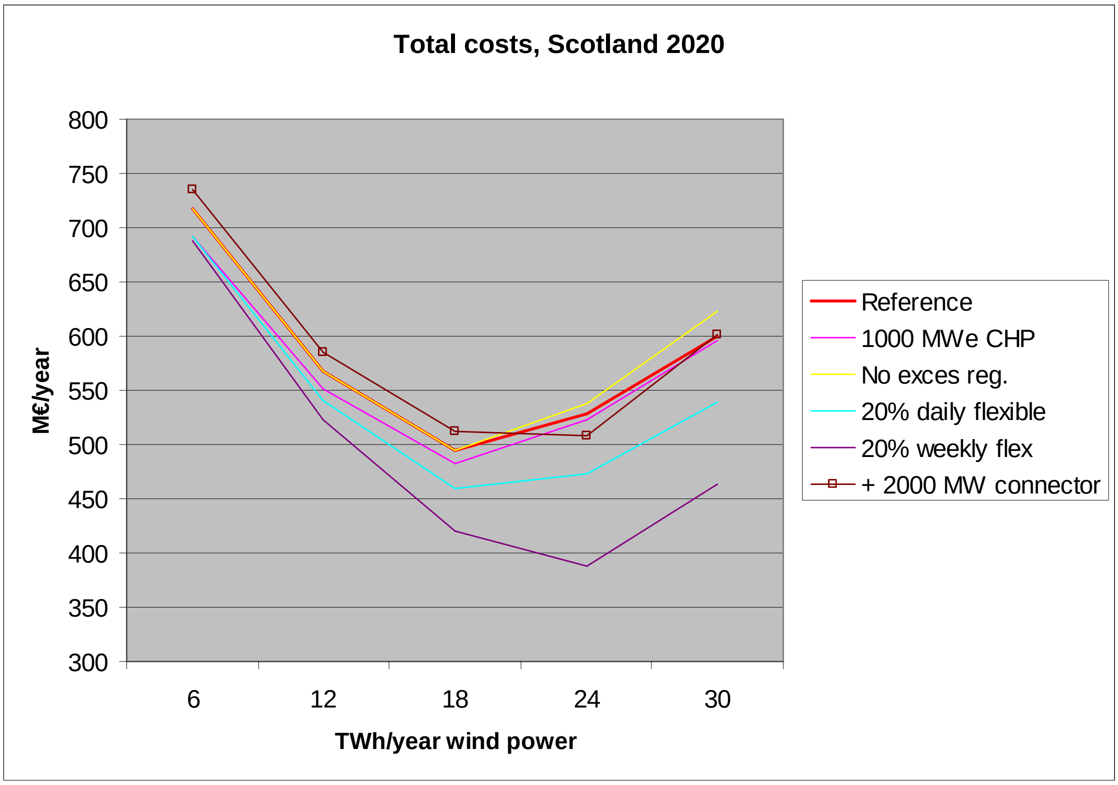


Fig. 3.6.2

Apart from the increase of interconnector capacity, which is seen from Fig. 3.6.2 to have a questionable economy, the following balancing possibilities have been investigated:

- conversion of 20 % of the demand to flexible demand (24 h and one week time frames)
- increase of the CHP capacity to 1000 MWe

Flexible demand is again seen to have strong positive effects, but it is noted that the costs of the conversion are not considered.

1000 MWe CHP is not enough to shift the optimal level of wind power but it is seen to be profitable.

The graph 'No excess regulation' shows less increase in costs than in e.g Germany. This is because the very low level of CHP and district heating leaves little room for regulation anyway.

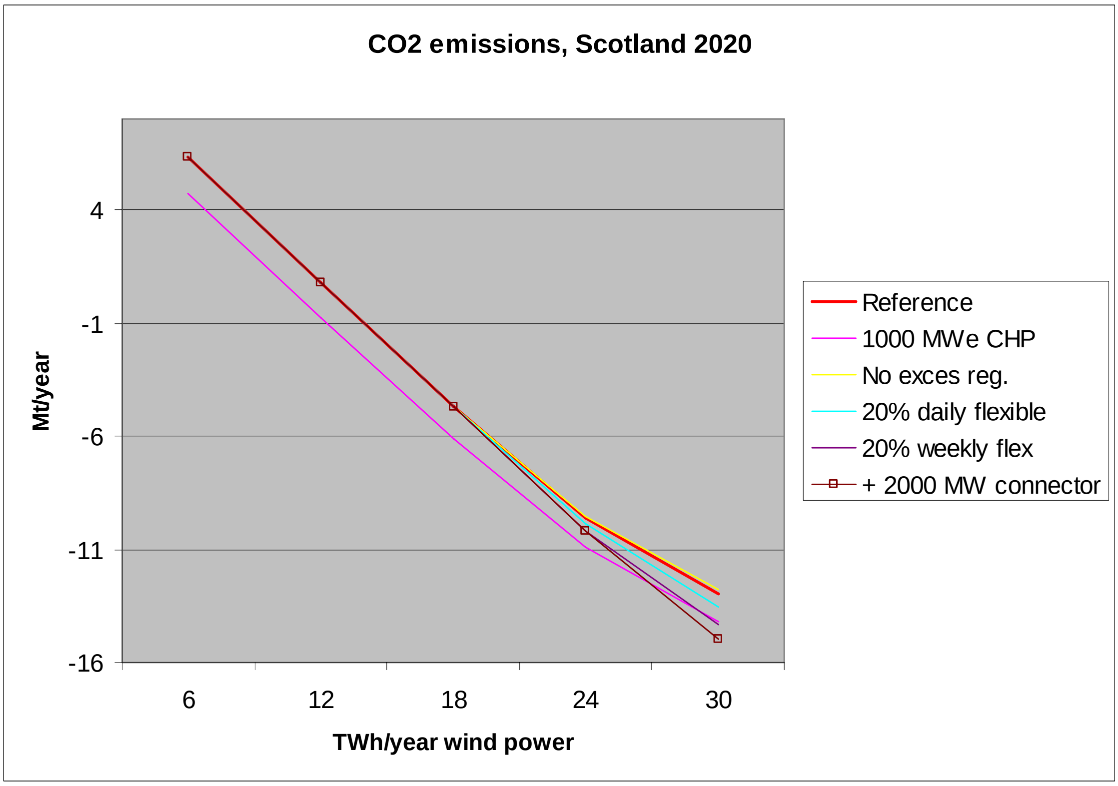
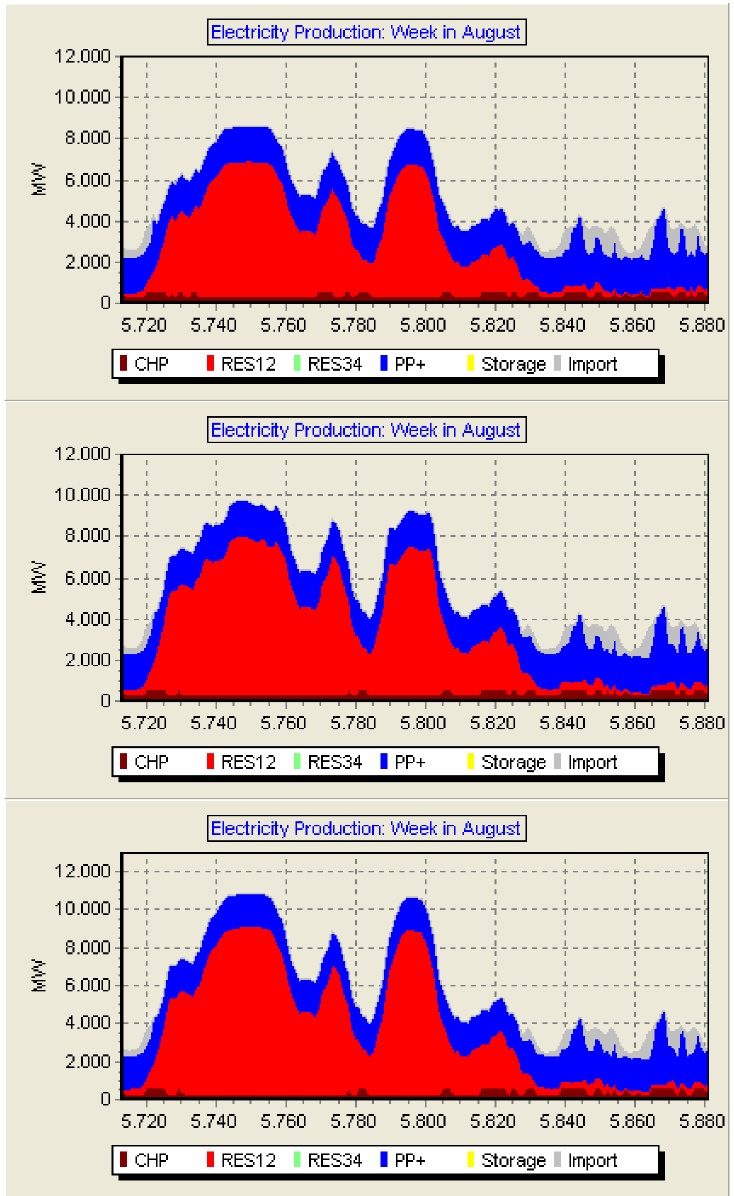


Fig. 3.6.3

The shape of the CO2 graph is similar to the graph of other regions with strong interconnectors (like Estonia), but the level is lower. A large export of electricity produced nearly 100% by nuclear and wind power causes high CO2 deficits.

The reservations regarding international balancing made in section 3.1 are, however, relevant to this case as wind power is also relevant to all the neighbouring regions.



Res12=wind. Top row: 18 TWh wind. Two bottom rows: 24 TWh

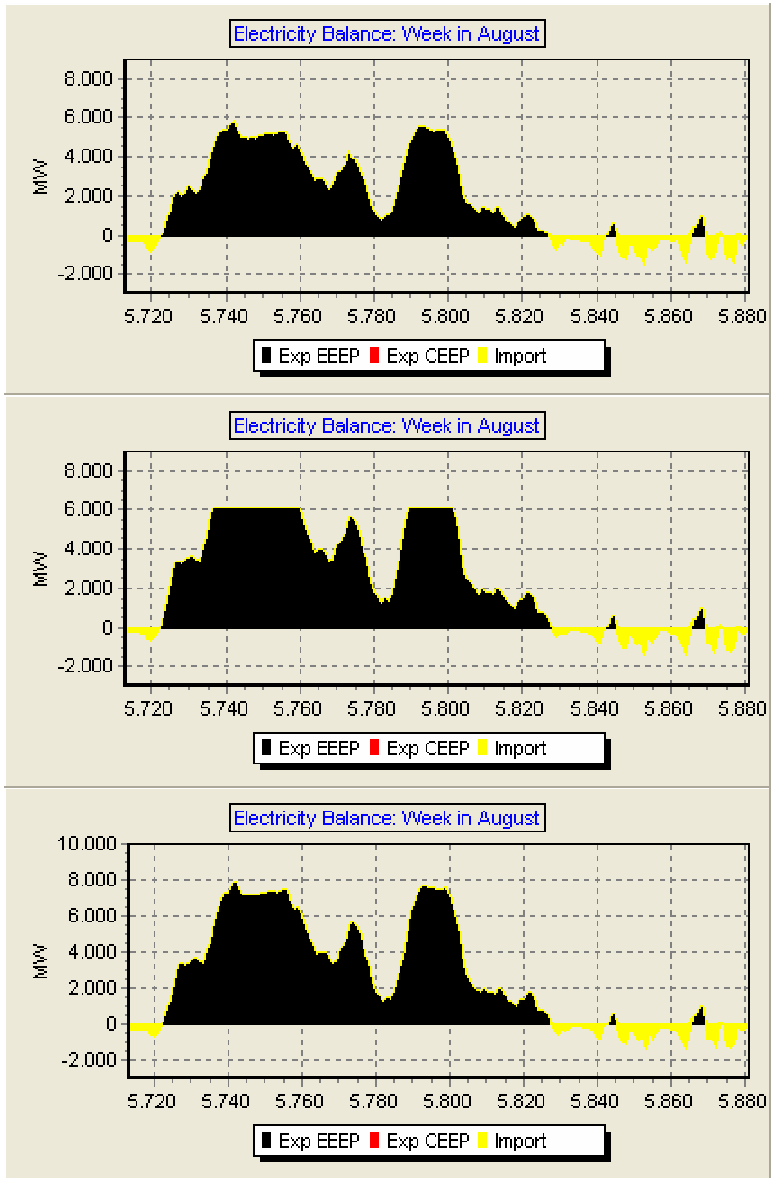


Fig. 3.6.4. Two top rows: 6000 MW interconnect. Bottom row: 8000 MW

4. Structural changes of the distribution network

The energyPLAN scenario calculations referred to above assume that a perfect market (or a centralised control system) allocates the production capacities hour by hour in a way which ensures either minimum excess electricity production or minimum socio-economic production costs. This is a sound methodology when the aim is to compare the potential of different capacity mixes or different control strategies, but it does not present a realistic picture of the functioning of the partially liberalised electricity market of today.

The reasons for this are analysed in a number of deliverables of the DESIRE project. However, this situation is being improved as both the markets and the technical systems are changing at considerable speed in the direction of more intelligence and flexibility.

This process has been studied by a number of EU projects and lately in the EU SmartGrid Technology Platform, which was launched in April 2006. The text below and Figure 4.1 show how the process involves many topics from micro grids to Smarter use of transmission lines.

Electricity grids of the future are Smart in several ways. Firstly, they allow the customer to take an active role in the supply of electricity. Demand management becomes an indirect source of generation and savings are rewarded. Secondly, the new system offers greater efficiency as links are set up across Europe and beyond to draw on available resources and enable an efficient exchange of energy. In addition, environmental concerns will be addressed, thanks to the exploitation of sustainable energy sources. The potential benefits are impressive, but how will they be achieved?

The platform, in turn, relies partly on the finding of the projects in the FP5 cluster: IRED. Among them DISPOWER and CRISP.

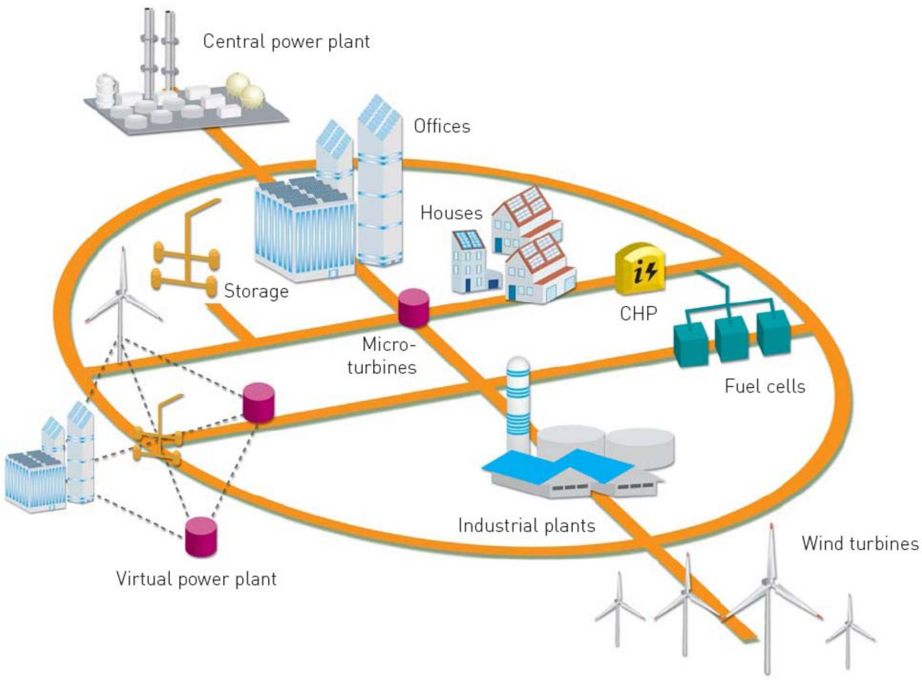


Figure 4.1. SmartGrids.

It is seen from these studies that the aim of the mentioned process is not just to improve the ability to incorporate fluctuating electricity sources but also to minimise the need for new costly interconnectors and – most of all – to improve the supply security in ‘open’ systems with many operators. These studies have two main headlines: a) more powerful communication networks;

b) a change from AC distribution systems towards DC systems involving HVSC (high voltage semi conductors). The first can provide more flexible and efficient balancing of fluctuating electricity productions. The latter can provide cheaper and more effective transmission and distribution systems with less environmental impact (underground cables).

In Denmark, where the need for changes is big because of the high share of wind power, a large-scale pilot test is taking place with a new way of organising the distribution system – the cell system. It is described in detail in ref [5]. It is part of a large project which has just been initiated by the Danish TSO, Energinet.dk, under the name: EcoGrid. [6] The aim of this project is to prepare the Danish transmission and distribution system for the present goal of the government: 50 % wind power in 2020.

The idea is to equip a distribution area at the medium voltage level (60 kV) with an extensive information network connecting all producers and a number of large consumers. This will create a semi-independent ‘cell’ where automatic balancing of as well active as reactive power can take place. In case of voltage break-downs at the higher levels of the transmission system, this cell can disconnect itself and continue operation in ‘island’ mode. The cell is situated in the Holsted area in Southern Jutland and encompasses wind turbines as well as CHPs. [7]

Similar projects are under way in Australia and the USA where a combination of new decentralised power plants (mainly N-gas combined cycle), high peak demands caused by air conditioning and a liberalised market has created a decreasing security of supply.[8]

5. Conclusions

In six regions in Denmark, Germany, the UK, Poland, Spain and Estonia, models of the electricity supply have been made and the magnitude of CHP regulation systems has been evaluated against other relevant measures including the expansion of interconnectors.

Interregional and international transmission lines play an important role in the balancing of fluctuating and partly unpredictable electricity productions and consumptions, in particular when they connect areas with fundamentally different systems of electricity production units. An example of this is the balancing of wind power and hydro power with reservoirs between Denmark and Norway.

However, the scenario calculations for 2020 for the six regions have shown that new interregional transmission lines usually do not form the most profitable and sustainable solution to the balancing problem caused by an increase of fluctuation in the electricity production. A range of technologies which can be applied to increase the internal balancing capacity has been analysed and described:

- CHP with heat stores (maybe with heat pumps)
- Flexible demands and Demand Side Management.
- Hydro power with reservoirs (maybe with reverse pumping).
- Electrical cars (battery, hybrid or fuel cell)

CHP with heat stores: Except from the case of Denmark, CHP is typically used today as base load or heat demand-oriented production. However, by use of heat stores, CHP may serve as a balancing instrument for peak load production, spot markets, manual reserve and possibly – as long as they are operating – even primary reserve. The operation hours may decrease, but such operation will allow for better integration of wind power. Heat pumps can be added and allow for improvements of both efficiencies and even further improvements of the integration of wind power.

Flexible demand and demand side management can be used for avoiding the peaks of excess wind power production. This involves e.g. heat stores in individual houses for demand response purposes. Hot water and space heat demands can partly be covered by heat stores with integrated electric heaters or, at best, be equipped with energy-efficient heat pumps.

Hydro power with reservoirs including reverse pumping can ideally be used for delivering positive and negative balancing power. Capacity can be retrieved from the storage when energy is needed and the electricity is typically available within minutes or even within one minute. The use of hydro power for European balancing will mainly apply to short-term and fast-responding power balancing requirements on small scale.

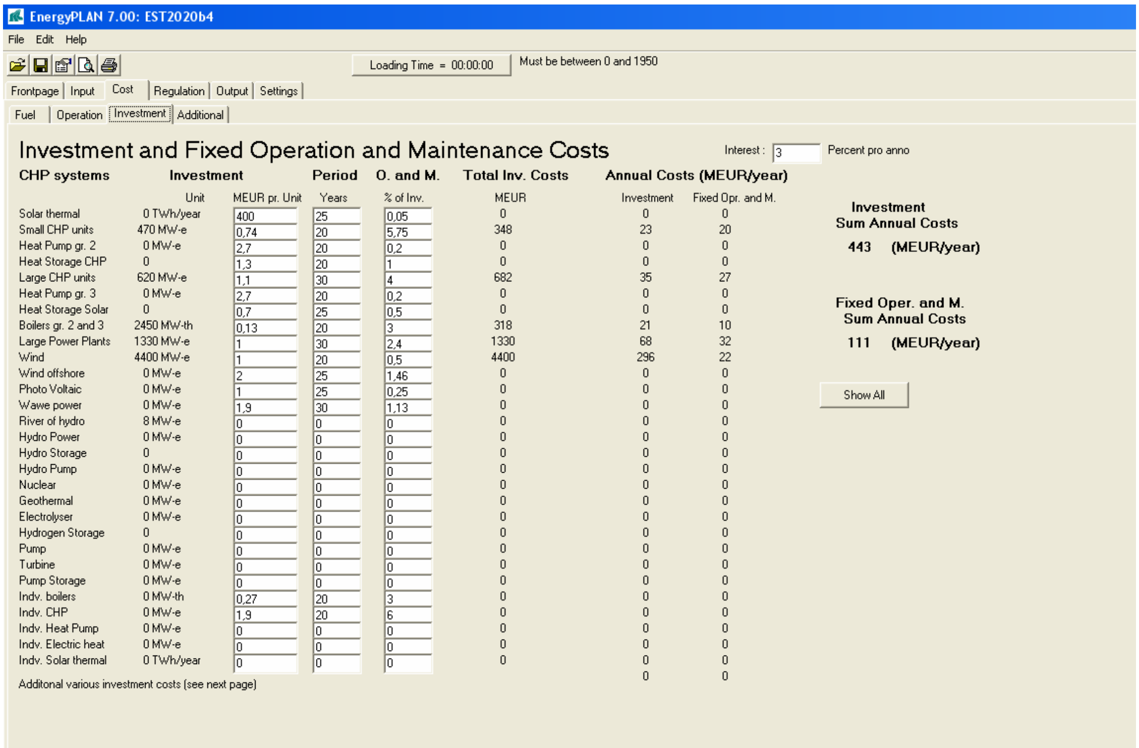
Electric cars: The integration of the electricity supply system and the transport system has been investigated as a long-term solution for the balancing of wind power. Positive socio-economic results have been found in the 2020 calculations in cases where the price difference between an ordinary car and a comparable battery car is reduced to 50% of today's level. This is due to the combined advantages of A: the balancing potential of the large combined capacity of the batteries, and B: the substitution of the expensive and CO2-emitting fuel, petrol.

The proposed internal balancing requires effective and fast markets for primary power as well as balancing power and reserve power. This in turn can only be implemented if new powerful communication networks linking all producers and major consumers are established.

The passing of this barrier is, however, assisted by a parallel effort by the TSOs: the creation of the 'cell structure' in the transmission and distribution system.

The intention behind this effort is to create smaller and more independent areas (cells) operating at the medium voltage levels below 100 kV. This structure can perform balancing of active as well as reactive power and can enable the single cells to disconnect from the transmission grid in situations where voltage break-downs are threatening to spread to large areas (even internationally).The need for these functions has increased with the increase of decentralised producers and the opening of the access to the grid.

Appendix 1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Investment and Fixed Operation and Maintenance Costs

Interest : 3 Percent pro anno

CHP systems	Investment Unit	Investment MEUR pr. Unit	Period Years	O. and M. % of Inv.	Total Inv. Costs MEUR	Annual Costs (MEUR/year) Investment	Annual Costs (MEUR/year) Fixed Opr. and M.
Solar thermal	0 TWh/year	400	25	0,05	0	0	0
Small CHP units	470 MW-e	0,74	20	5,75	348	23	20
Heat Pump gr. 2	0 MW-e	2,7	20	0,2	0	0	0
Heat Storage CHP	0	1,3	20	1	0	0	0
Large CHP units	620 MW-e	1,1	30	4	682	35	27
Heat Pump gr. 3	0 MW-e	2,7	20	0,2	0	0	0
Heat Storage Solar	0	0,7	25	0,5	0	0	0
Boilers gr. 2 and 3	2450 MW-th	0,13	20	3	318	21	10
Large Power Plants	1330 MW-e	1	30	2,4	1330	68	32
Wind	4400 MW-e	1	20	0,5	4400	296	22
Wind offshore	0 MW-e	2	25	1,46	0	0	0
Photo Voltaic	0 MW-e	1	25	0,25	0	0	0
Wawe power	0 MW-e	1,9	30	1,13	0	0	0
River of hydro	8 MW-e	0	0	0	0	0	0
Hydro Power	0 MW-e	0	0	0	0	0	0
Hydro Storage	0	0	0	0	0	0	0
Hydro Pump	0 MW-e	0	0	0	0	0	0
Nuclear	0 MW-e	0	0	0	0	0	0
Geothermal	0 MW-e	0	0	0	0	0	0
Electrolyser	0 MW-e	0	0	0	0	0	0
Hydrogen Storage	0	0	0	0	0	0	0
Pump	0 MW-e	0	0	0	0	0	0
Turbine	0 MW-e	0	0	0	0	0	0
Pump Storage	0 MW-e	0	0	0	0	0	0
Indv. boilers	0 MW-th	0,27	20	3	0	0	0
Indv. CHP	0 MW-e	1,9	20	6	0	0	0
Indv. Heat Pump	0 MW-e	0	0	0	0	0	0
Indv. Electric heat	0 MW-e	0	0	0	0	0	0
Indv. Solar thermal	0 TWh/year	0	0	0	0	0	0
Additonal various investment costs (see next page)						0	0

Investment Sum Annual Costs: 443 (MEUR/year)

Fixed Oper. and M. Sum Annual Costs: 111 (MEUR/year)

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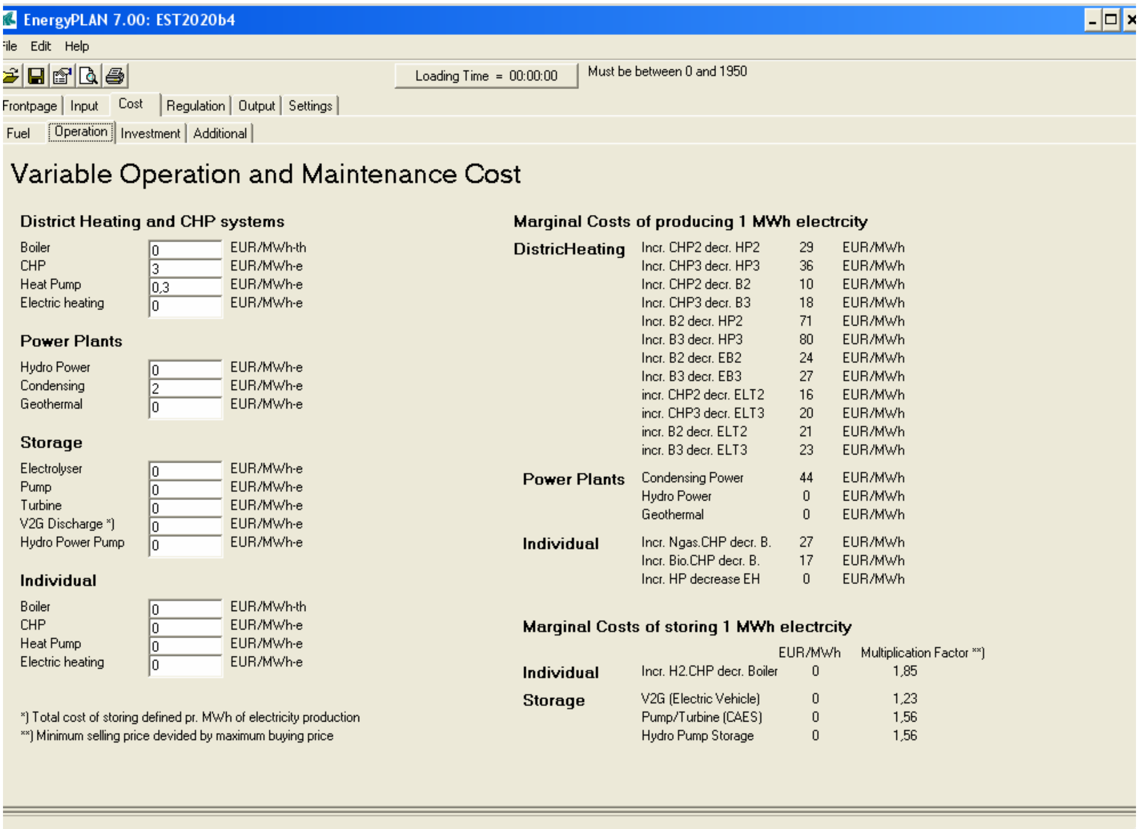
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Variable Operation and Maintenance Cost

District Heating and CHP systems

Boiler	0	EUR/MWh-th
CHP	3	EUR/MWh-e
Heat Pump	0,3	EUR/MWh-e
Electric heating	0	EUR/MWh-e

Power Plants

Hydro Power	0	EUR/MWh-e
Condensing	2	EUR/MWh-e
Geothermal	0	EUR/MWh-e

Storage

Electrolyser	0	EUR/MWh-e
Pump	0	EUR/MWh-e
Turbine	0	EUR/MWh-e
V2G Discharge *)	0	EUR/MWh-e
Hydro Power Pump	0	EUR/MWh-e

Individual

Boiler	0	EUR/MWh-th
CHP	0	EUR/MWh-e
Heat Pump	0	EUR/MWh-e
Electric heating	0	EUR/MWh-e

*) Total cost of storing defined pr. MWh of electricity production

**) Minimum selling price devided by maximum buying price

Marginal Costs of producing 1 MWh electrcity

DistricHeating	Incr. CHP2 decr. HP2	29	EUR/MWh
	Incr. CHP3 decr. HP3	36	EUR/MWh
	Incr. CHP2 decr. B2	10	EUR/MWh
	Incr. CHP3 decr. B3	18	EUR/MWh
	Incr. B2 decr. HP2	71	EUR/MWh
	Incr. B3 decr. HP3	80	EUR/MWh
	Incr. B2 decr. EB2	24	EUR/MWh
	Incr. B3 decr. EB3	27	EUR/MWh
	incr. CHP2 decr. ELT2	16	EUR/MWh
	incr. CHP3 decr. ELT3	20	EUR/MWh
	incr. B2 decr. ELT2	21	EUR/MWh
	incr. B3 decr. ELT3	23	EUR/MWh
Power Plants	Condensing Power	44	EUR/MWh
	Hydro Power	0	EUR/MWh
	Geothermal	0	EUR/MWh
Individual	Incr. Ngas.CHP decr. B.	27	EUR/MWh
	Incr. Bio.CHP decr. B.	17	EUR/MWh
	Incr. HP decrease EH	0	EUR/MWh

Marginal Costs of storing 1 MWh electrcity

		EUR/MWh	Multiplication Factor **)
Individual	Incr. H2.CHP decr. Boiler	0	1,85
Storage	V2G (Electric Vehicle)	0	1,23
	Pump/Turbine (CAES)	0	1,56
	Hydro Pump Storage	0	1,56

(actual capacity figures refer to the Estonian reference)

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